

KENTUCKY GOVERNOR'S  
OFFICE OF ENERGY POLICY

*REPORT ON RATE DESIGN AND  
RATEMAKING ALTERNATIVES AS THEY  
IMPACT ENERGY EFFICIENCY*

*PREPARED BY*

**La Capra Associates, Inc.**

Twenty Winthrop Square  
Boston, MA 02110

Lee Smith  
*Managing Consultant*

Technical Report

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## INTRODUCTION

La Capra Associates was retained by the Kentucky Governor's Office of Energy Policy to conduct a study to determine the potential financial, social and economic impacts of alternative rate design structures and ratemaking methodologies that may encourage increased utilization of and investment in cost-effective energy efficiency and other demand response resources. This report is the implementation of Governor Ernie Fletcher's Executive Order 2006-1298, which called for the Office of Energy Policy to analyze the impact of incorporating energy efficiency as a goal of retail rate design. We interpret the purpose of this report as that of providing information to decision makers regarding how potential changes in rate design and ratemaking methodology may impact energy efficiency, utilities, and ratepayers in Kentucky.

The report is divided into two sections or tasks. The first section discusses alternative rate design structures and how they may impact energy usage in the state. The second section examines issues related to decoupling of rates and contrasts decoupling with alternative rate design. The specific tasks to be analyzed included:

- 1 A Analysis of Kentucky Rate Structures**
- 1 B Review of Kentucky Electric Supply Cost**
- 1 C Review of Alternative Rate Structures**
- 1 D Analysis of Impact of Rate Structures on Energy Efficiency**
- 2 A Review of Kentucky Ratemaking Methodology**
- 2 B Assessment of the Benefits and Drawbacks of the Current Ratemaking Methods**
- 2 C Alternative Ratemaking Methodologies**
- 2 D How DSM Programs Can Be Implemented and Costs Recovered**

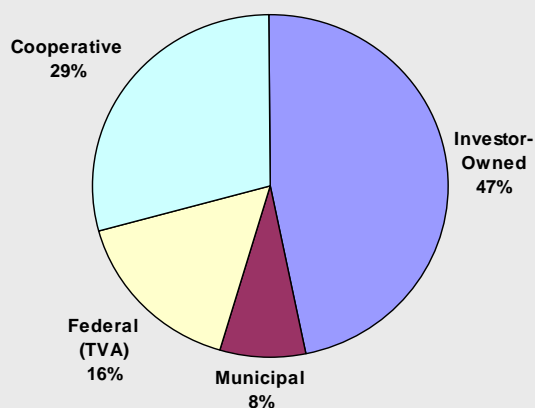
### Background

Kentucky electricity consumers, depending on service territory and customer type, are served by four different types of providers. Electricity providers include investor-owned utilities ("IOU"), electric cooperatives ("COOPs"), municipal utilities, and a federal power authority, Tennessee Valley Authority ("TVA").

Kentucky's four IOUs, Kentucky Power (American Electric Power), Kentucky Utilities ("KU"), Louisville Gas & Electric ("LG&E"), and Duke Energy are responsible for almost half of the retail sales of electricity in the state.

2005 Retail Sales by Utility Category

2005 EIA Reported Retail Sales by Utility Category  
(Total = 89,351 GWh)



In addition to the four IOUs, two generation and transmission cooperatives (“G&T COOPs”), Big Rivers Electric Corporation and East Kentucky Power Cooperative, serve 19 rural electric cooperative corporations, which make up almost 30% of sales in the state. IOUs and COOPs are regulated by the Kentucky Public Service Commission (“PSC”) in varying degrees. The remaining two types of service providers, municipals and TVA, are not regulated by the PSC. For purposes of this analysis, the focus will be on the regulated utilities and the load they serve.

Historically, Kentucky has been a low energy cost state. Its power supply depends heavily on relatively low-cost coal generation. Currently, more than 90% of energy produced in Kentucky is from coal, which keeps energy costs low. Also, much of the coal generating capacity is greater than 30 years old, which means that capacity costs are low due to depreciation of this capacity. As a result of the low electric rates, there has been less of an incentive in Kentucky to conserve energy and to invest in energy efficiency than in most areas of the country. Where customers are paying ten cents per kWh and greater, there is more incentive, than has existed in Kentucky, for customers and for utilities to institute measures that reduce electric usage

However, Kentucky’s electric industry is facing multiple challenges now and in the future. Recently, there have been dramatic increases in coal, gas, and oil fuel costs that have resulted in increased rates to IOU customers. Environmental regulations have caused and will cause additional upward pressure on rates. Cooperative utilities purchase much of their power, and their costs have increased because of higher, more volatile, market-based energy prices.

Going forward, the utilities are building a number of new coal generating units to meet fast growing demand. There is a PSC report that predicts that by 2025, Kentucky will need an additional 7000 MWs to meet the needs of a growing economy. New units will also be required to replace some older generating units. Investing in new generation will increase rates.

In addition to the impact that new generation will have on electric rates, it is likely that new environmental regulations will increase electric rates. For example, there is an increasing likelihood that some form of a federal greenhouse gas policy may take effect in the near term, which would significantly impact the cost of electricity from fossil fuel-based generation, especially coal. Additionally, federal policies are encouraging more efficient use of energy, since producing less energy is generally more environmentally benign than producing more energy.

#### 2005 Average Retail Rates

The estimated average total retail rates (based on retail sales revenues divided by retail sales) in Kentucky for 2005 were as follows:

Sectors	2005 State Average Electricity Rates (cents/kWh)
Residential	6.57
Commercial	6.01
Industrial	3.60
All Sectors	5.01

These rates are quite low compared to rates in most states across the country; however, this table understates current rate levels, as there have been significant rate increases since 2005. Fuel costs have increased, and in 2006, several Kentucky utilities (Duke Energy, EKPC, and Kentucky Power) received approvals for base rate increases of 7% to 21%, depending on the customer class.

For all of these reasons, the Governor and the GOEP are interested in how energy efficiency can be fostered in Kentucky. Kentucky's Energy Strategy includes among its recommendations the following:

- Maintain Kentucky's low-cost energy;
- Responsibly develop Kentucky's energy resources; and
- Preserve Kentucky's commitment to environmental quality.

Energy efficiency can be a major contributor to all of these objectives. How will such energy efficiency occur, and what energy policies will encourage energy efficiency? There are three basic possible sources that can improve energy efficiency: government actions; customer actions; and utility programs. The state can act directly to institute programs or building standards or tax incentives to encourage energy efficiency. State regulators can also influence customer actions through their regulation of rate design, and can influence utility programs through their ratemaking authority.

As a result of having low incentives to invest in energy efficiency in the past, there are many more opportunities for low-cost investments in energy efficiency than in states that have had high electric prices for years. In other words, there is likely a significant amount of low cost measures that can be instituted.

### ***Energy Efficiency Terminology***

Energy efficiency is sometimes thought of as measures that result in providing the same services with less energy. To be consistent with Kentucky's goal of maintaining low-cost energy, this report is using a somewhat broader definition, which is providing the same services at a lower energy cost. This encompasses both conservation and load shifting, which are defined below.

- **Conservation** of energy refers to reducing the amount of energy used. Lowering load across most hours reduces the need to build additional coal generation. Examples of actions that result in conserving energy include increasing the level of building insulation, and utilizing high efficiency lighting.
- **Load shifting** refers to shifting some energy from more expensive periods to less expensive. Load shifting reduces the need to build additional generation (typically gas-fired units) to meet peak load. Examples of devices that result in load shifting from peak hours to off-peak hours would include control devices on customer appliances and ice chillers, that use electricity during off-peak hours to make ice for air cooling.
- **Demand Side Management ("DSM")** refers to efforts to lower load and to shift load. Programs, run by utilities or by other entities, may encourage both types of change that should improve energy efficiency. Throughout this report, we will describe the energy efficiency programs run by utilities as DSM programs.
- **Demand response** refers to a change in load usage as a result of specific rates and by DSM programs; demand response is a substitute for supply resources.

## TASK 1: ALTERNATIVE RATE DESIGN

### **Task 1A: Rate Structures**

Before describing the electric rates that exist in Kentucky, we will provide a generic introduction to electric rate design.

#### **Electricity Rates Primer**

Electricity rates typically seen in customer bills are made up of three main components, along with riders and adjustments. The components and characteristics of rates are:

- **Customer charge** is a monthly charge which does not vary with usage and is same for all customers within rate group;
- **Demand charge** varies based on the greatest amount of energy used at one point in time in a month or peak usage in a month(also called a capacity charge);<sup>1</sup>
- **Energy charge**, measured in kilowatt-hours (kWh), is charged based on how much electricity a customer uses.

Rates are determined for customer groups that share similar characteristics, such as residential customers and different size (usually defined in terms of customer's peak load) commercial and industrial customers. Typically, a single rate is offered to each customer group. When energy charges do not vary by time<sup>2</sup>, the signal to the customer is that the next kWh costs the same as the last. From an economics standpoint, the flat rate approach is inconsistent with how the cost of energy varies depending on a number of variables including the time of day, the season, and customers' individual peak demands. In a later section, we will discuss how alternative rate designs can reflect variation in the cost of electricity.

In addition to the basic rates, many utilities add on riders and adjustments to accomplish specific goals. Riders are additional charges that may be adjusted frequently, usually to track specified costs. Below, we discuss some of the riders in Kentucky that may impact customers' rates and usage.

- **Load Reduction Incentive Rider** is a rate offered to those with stand-by generating capacity that can be called upon when needed.
- **Fuel Clause Adjustment** permits the utility to adjust rates based on the cost of fuel. Since utilities have little control over fuel costs, this adjustment allows them to recover those costs without having to enter into costly and time consuming rate cases.<sup>3</sup>

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<sup>1</sup> This requires a demand meter, so it is usually not applicable to small customers.

<sup>2</sup> This is described as a flat, nonseasonal rate.

<sup>3</sup> The fuel adjustor does not communicate monthly cost differentials accurately because of the lag in the collection of the change in costs.

- **The DSM Cost Recovery Mechanism<sup>4</sup>** allows utilities to recover direct program costs, to be compensated for lost revenue and to earn an incentive. This is calculated using a predefined formula.
- **The Environmental Surcharge** allows utilities to recover all costs associated with complying with environmental regulations applicable to coal combustion wastes and by-products that are not recovered in base rates, including a return on capital costs.

### ***Representative Rate Structures in Kentucky***

For analytical purposes of this report, we are focusing on IOUs and COOPs. They represent the majority of load in the state. In order to estimate the impact of potential rate changes on the State of Kentucky, La Capra Associates gathered a sampling of rates impacting major classes of the IOUs and of the COOPs. The customer classes examined were Residential, General Service (GS), Large Commercial and Industrial ("C&I"). Specifically, we reviewed the rates of Kentucky Utilities, Kentucky Power, and Blue Grass Energy, a distribution cooperative that is a member of the East Kentucky Power Cooperative, as representative of rate structures in Kentucky. Each utility offers slightly different rate structures.

### **Sample Rates for Kentucky Utilities fall 2007**

#### ***Kentucky Utilities***

<b>Characteristic</b>	<b>Residential</b>	<b>General Service</b>	<b>Large C&amp;I (Primary)</b>	<b>Large C&amp;I Time-of-Day</b>
Customer charge	\$5.00	\$10.00	\$75.00	\$120.00
Energy charge (per kWh)	\$0.04865	\$0.05818	\$0.02501	\$0.02501
Demand charge (per kW)			\$6.81	On \$5.16 Off \$0.75
Fuel Adjustment (July) (per kWh)	\$0.00947	\$0.00947	\$0.00947	\$0.00947
Demand-Side Management Adjustment (per kWh)	\$0.00122	\$0.0014	-	-
Seasonality	None	None	None	None

<sup>4</sup> The mechanism to recover revenues from IOU DSM programs is described in Appendix A.

**Kentucky Power**

Characteristic	Residential	Small General Service	Large C&I (Primary)	Large C&I Time-of-Day
Customer charge	\$5.86	\$11.50	\$127.50	\$276
Energy charge (per kWh)	\$0.06002	\$0.08824 first 500 \$0.04805 over 500	\$0.04415	\$0.02044
Demand charge (per kW)		\$3.36 plus \$2.97 excess reactive	\$3.36 plus \$2.97 excess reactive	On \$11.53 Off \$ 3.31
Fuel Adjustment (July) (per kWh)	\$0.00363	\$0.00363	\$0.00363	\$0.00363
Demand-Side Management Adjustment (per kWh)	\$0.000637	-	-	-
Seasonality	None	None	None	None

In developing representative IOU marginal electric rates below, we averaged the IOU rates by weighting these rates by sales by customer class. The customer charge is not included because it is not a marginal rate.

**IOU Average Marginal Electric Rate<sup>5</sup>**

Characteristic	Residential	General Service	Large C&I (Primary) <sup>6</sup>
Energy charge (per kWh)	\$0.05196	\$0.0562	\$0.03185
Demand charge (per kWh)	NA	\$0.00181 <sup>7</sup>	NA
Demand charge (per kW)	0	NA	\$5.58
Fuel Adjustment (July) (per kWh)	\$0.00777	\$0.00832	\$0.00738
Demand-Side Management Adjustment (per kWh)	\$0.00087	\$0.00112	\$0
Total Marginal Cost to Consumer (per kWh)	\$0.06059	\$0.06744	\$0.03924

<sup>5</sup> Average marginal rates for the IOUs were calculated by taking a weighted average of the Kentucky Power and Kentucky Utilities rates.

<sup>6</sup> The large C&I average does not reflect the Time of Day rates.

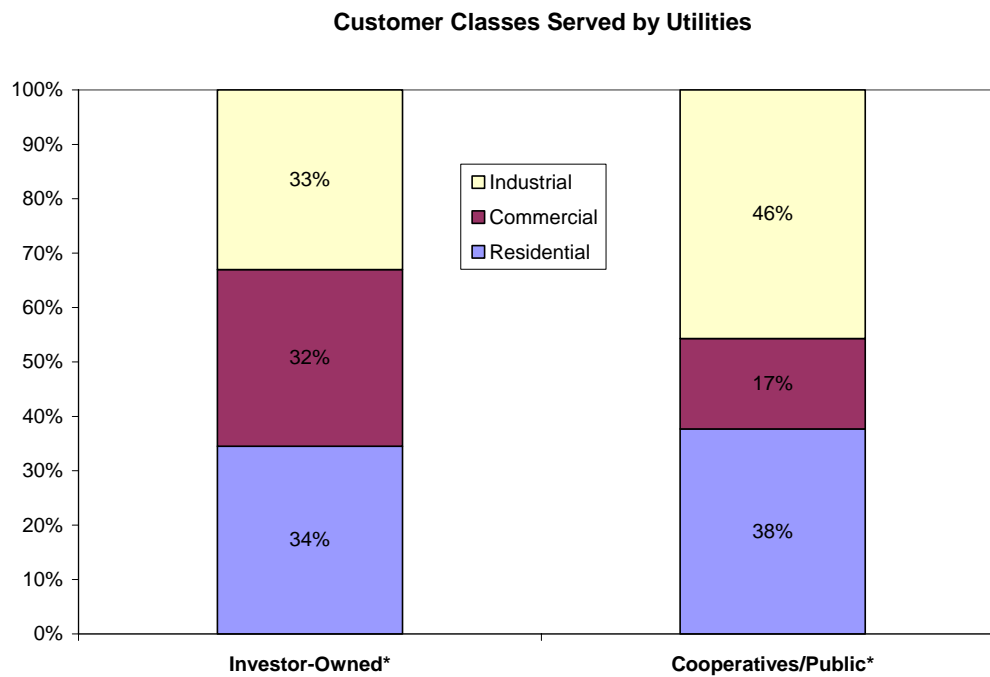
<sup>7</sup> Since Kentucky Utilities does not apply a demand charge to smaller general service customers, we have estimated what energy rate the Kentucky Power demand charge to smaller general service customers is equivalent to. The estimate assumes a 50% load factor.

**East Kentucky Power Cooperative – Blue Grass Energy**

Characteristic	Residential	Small C&I	Large C&I <sup>8</sup>
Customer charge	\$5.30	\$6.95	\$24.00
Energy charge (per kWh)	\$0.06028	\$0.06453 first 3,000 kWh \$0.05973 over 3,000 kWh	\$0.04945-1st 10,000 kWh \$0.04275 – next 15,000 \$0.03715 – next 50,000 \$0.03485 – next 75,000 \$0.03315 – over 150,000
Demand charge (per kW)		\$6.23 over 10kW	\$6.23
Fuel Adjustment (July) (per kWh)	\$0.00583	\$0.00583	\$0.00583
Seasonality (per kW)	None	None	None

We utilize these actual sample rates to draw general conclusions about average IOU and COOP<sup>9</sup> rates throughout the state. Below is the customer break-down by customer classes of IOUs and COOPs in Kentucky.

Figure 1



\*Estimates derived from 2005 EIA data.

<sup>8</sup> The rate for large C&I customers here is represented by a declining block rate, where more usage results in lower unit rates.

<sup>9</sup> Blue Grass Energy Cooperative is assumed to be typical of the distribution cooperatives taking power from East Kentucky. The cooperatives that take power from Big Rivers Corporation serve primarily industrial load and are not reflected in this analysis.

**TASK 1B: Kentucky Supply Cost****Electric Supply Cost Primer**

There are a number of distinctions between electric costs that need to be clarified before discussing electric costs.

- 1) The first distinction is that separate costs can be identified for the supply (generation) function, the transmission function, and the distribution function. Since the primary goal of energy efficiency is its impact on the cost of supply, we focus on the cost of supply in this report.<sup>10</sup>
- 2) The second distinction is between energy and capacity costs. Energy costs are equivalent to variable costs (which vary with consumption) and capacity costs, (which do not vary in the short-run) are viewed as fixed costs because they typically reflect major capital investments.

**Marginal Costing Theory**

Marginal supply costs consist of short-run marginal energy costs and marginal capacity costs, which are added to marginal energy costs to measure long-run marginal costs. Short-run marginal energy costs are made up of the cost of fuel and variable O&M. When a customer uses an additional unit of energy, utility costs increase by the short-run marginal cost. The actual marginal energy cost for each particular utility will depend on its mix of generating sources. Marginal energy costs are normally higher than average energy cost. Marginal capacity costs reflect a longer run view: if load increases, additional capacity will be needed. Increases in peak load will require that the utility acquire more generating capacity, which gives rise to the marginal capacity cost.

The marginal cost of capacity is usually considered to be the cost of the least-capital intensive technology, which, generally, is a Combustion Turbine.

- 3) The third distinction is between average and marginal costs. The average cost of supply is, as it sounds, the total cost of supply divided by the total quantity supplied. The marginal cost of supply is what it costs to produce an additional unit of supply. In the short-run, additional kilowatt-hours (kWhs) can be produced only by increasing production from existing generating units, so the short-run marginal cost is basically fuel. In the long-run, additional kWhs can be produced by building additional generating units. Marginal costs are crucial to providing customers with price signals. Only if prices<sup>11</sup> reflect marginal costs can customers make economically efficient decisions.

Average costs and marginal costs are related over time. If marginal costs are higher than average costs, average costs will increase in the future as electric demand grows.

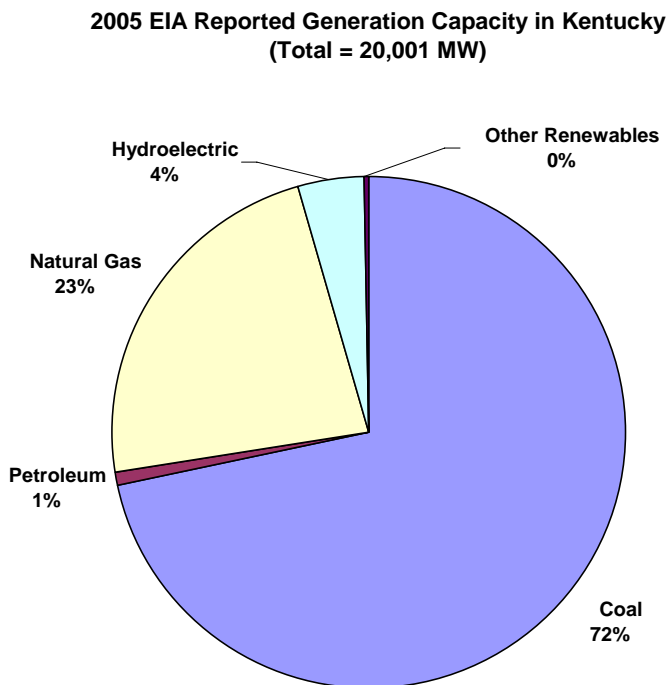
<sup>10</sup> In the long-run there are also marginal transmission and distribution costs which may be avoided through either load reduction or load shifting. These tend to be small relative to marginal supply costs, and we are not addressing them.

<sup>11</sup> The prices that should signal marginal costs are those that apply to incremental usage. Thus if all customers use 100 kWhs, the monthly customer charge and the price for the 1<sup>st</sup> 100 kWhs are not very relevant as price signals.

### ***Average Cost of Electricity in Kentucky***

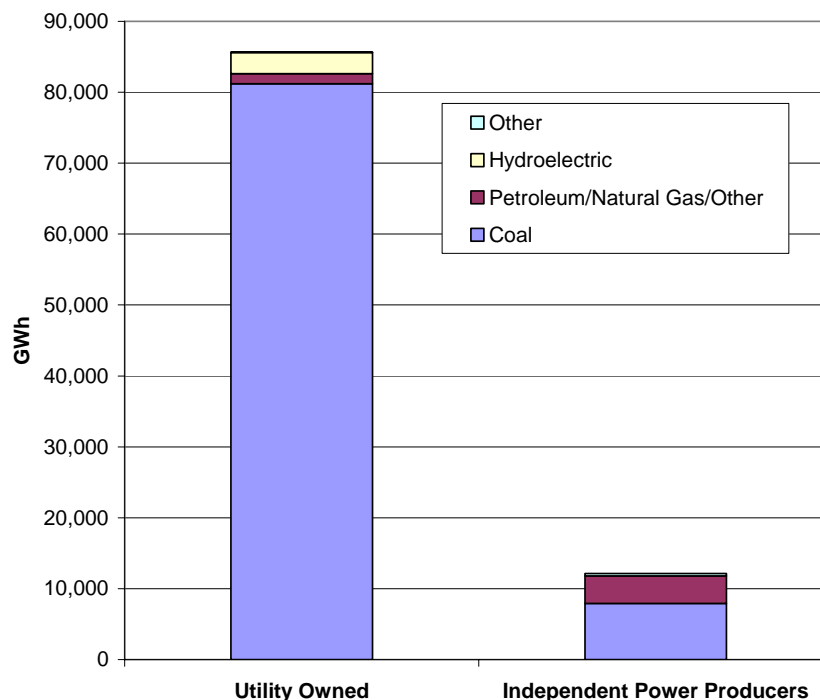
Over 20,000 megawatts (“MW”) of generation capacity are located in Kentucky, most of which are utility-owned, though some are owned by Independent Power Producers (“IPPs”). While 72% of the state’s generation capacity is coal-based, these generate over 90% of the electricity produced in the state. Since 2000, more than 3,300 MWs of natural gas fired generation capacity have come on-line in the state, though some of this power is sold on the wholesale market.<sup>12</sup>

Figure 2



<sup>12</sup> No additional new power plants have been completed since 2005 in Kentucky. However, several projects are currently under construction.

Figure 3

**2005 EIA Electric Generation by Utilities and IPPs in Kentucky**

Generating resources owned by IOUs provide most of the energy serving IOU load. Their average supply cost therefore consists of a return and depreciation on their generating plants and the fuel and operating and maintenance expense associated with these plants. The COOPs, however, purchase a larger proportion of the energy and capacity they use from third parties. This means that their average cost is more affected by market-based pricing, which is more volatile and which has been higher than the cost of owned generation in recent years.

It is important to note that one of the reasons that average electric rates in Kentucky have been low is that capital costs reflected in Kentucky rates have been low because many generating plants are more than thirty years old, and older plants are very heavily depreciated. Going forward, adding more capacity to meet growing loads will increase average rates; adding new capacity also to replace aging capacity will increase rates still further.

***Marginal Cost of Electricity Supply in Kentucky***

The cost that is most relevant to designing rates that provide appropriate price signals for energy efficiency is the long-run marginal cost of supply. The marginal cost of supply (also referred to as generation) includes the cost of additional energy (primarily fuel) and the cost of additional capacity. For customers to make efficient long-run decisions about appliance purchases and housing stock, they need to be able to compare the additional amount they will spend for the

purchase with the savings in electric bills that will result from the purchase. They cannot make efficient decisions if rates do not provide them with price signals regarding future electric costs. Thus rates should include a reflection of marginal capacity costs. Other costs that should be considered are those that may result from federal action regarding environmental regulations. Federal, state, or local regulations regarding air emissions, water resources, land resources, and even aesthetics may all increase the cost of electricity. If the impact of likely and potential new regulations, particularly environmental regulations on Kentucky utilities is reflected in the utilities' projections of supply costs and of marginal costs, the next DSM screening analyses would find that many more energy efficiency measures would appear cost-effective and would pass the screening tests.

While concern has been focused on marginal supply (both energy and capacity) costs, increasing load will also increase transmission costs, as Kentucky's existing transmission facilities are heavily used. New transmission will have to be built to meet load growth. Building new transmission has become increasingly expensive and also difficult to site. We have included in our estimates of the cost of supply a very conservative estimate of the cost of additional transmission to deliver that supply.<sup>13</sup>

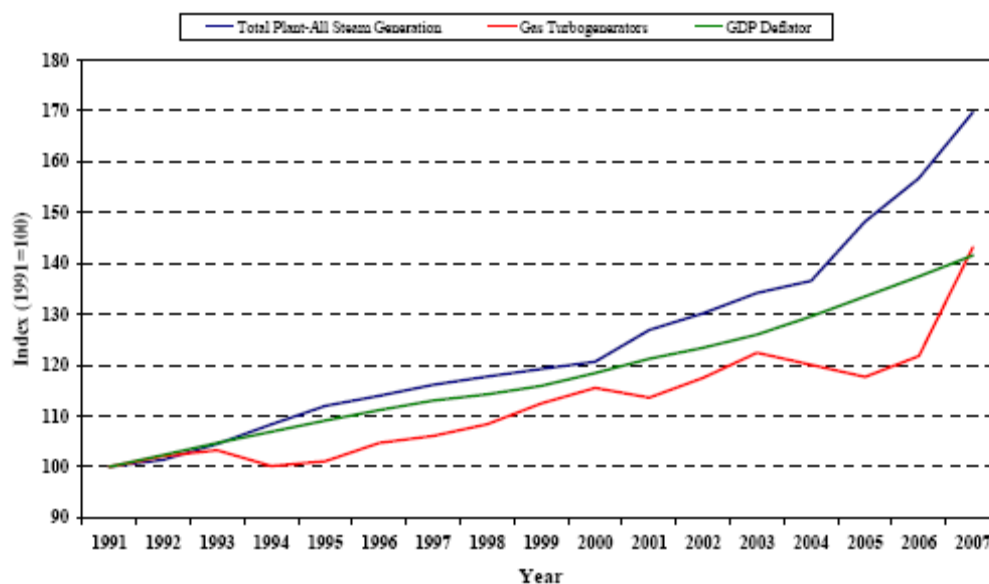
We expect that the marginal cost of supply is higher than average supply cost in Kentucky. This is true of the marginal cost of energy, as more than 90% of the energy is produced by coal baseload generation, but during some peak hours the marginal cost will most likely be determined by natural gas-fired generation. It is also true of the marginal cost of generating capacity. Adding new capacity is also much more expensive than the average capacity cost of existing generation, which as noted above has been significantly partially depreciated due to age. New generation capacity is more expensive than older generation. Moreover, the cost of building new generation has risen sharply in the last few years as a result of escalating material costs, a weakening U.S. dollar, and increasing labor costs. Based on the Handy Whitman Index©, a set of indices that track the cost of various generation components, the graph below shows that the cost of steam units increased by about 25% between 2004 and 2007.<sup>14</sup> Furthermore, gas turbine costs experienced an 18% increase just in the past year. The extent of future increases is difficult to estimate, but growth in global demand for materials will likely continue to put pressure on new generation costs. This translates to even higher marginal costs for new capacity than previously estimated by Kentucky utilities.

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<sup>13</sup> There are also marginal distribution costs, which we are not attempting to address, as they are very specific to the utility and local conditions.

<sup>14</sup> Graph is an excerpt from "Rising Utility Construction Costs: Sources and Impacts," The Brattle Group, September 2007. <[http://www.eei.org/industry\\_issues/electricity\\_policy/state\\_and\\_local\\_policies/rising\\_electricity\\_costs/Rising\\_Utility\\_Construction\\_Costs.pdf](http://www.eei.org/industry_issues/electricity_policy/state_and_local_policies/rising_electricity_costs/Rising_Utility_Construction_Costs.pdf)>

Figure 4

**National Average Generation Cost Index**

Sources: The Handy-Whitman® Bulletin, No. 165 and the U.S. Bureau of Economic Analysis.  
Simple average of all regional construction and equipment cost indices for the specified components.

*Excerpt from The Brattle Group*

Some Kentucky utilities have plans in progress to build at least another 1300 MW of coal-based generation and about 200 MW of natural gas-fired combustion turbines in the next five years.<sup>15</sup> Furthermore, Kentucky Utility and Louisville Gas and Electric combined are also planning for more than 1000 MW of additional combustion turbines between 2013 and 2018 to meet future demand growth.<sup>16</sup> To the extent that the most recent DSM plans may expand DSM savings, forecasted needs may have decreased since these plans were offered.

Table 1: Utility Generation Under Construction or Planned

Unit Type	Plant/Unit Name	Capacity (MW)
Coal	Trimble County Coal Facility	750
Coal	Spurlock Unit #4	278
Coal	Smith Unit #1	278
Combustion Turbine	Smith Unit #8	100
Combustion Turbine	Smith Unit #9	100
Combustion Turbine	Misc. 2013-2018	1086

<sup>15</sup> Coal Units: Trimble County Coal Facility (750 MW), Spurlock Unit #4 (278 MW) and Smith Unit #1 (278 MW). CT Units: Smith Units #8 (100 MW) and #9 (100 MW).

<sup>16</sup> "Staff Report on the 2005 Integrated Resource Plan Report of Louisville Gas and Electric Company and Kentucky Utility Company," Kentucky Public Service Commission.

In estimating the marginal capacity cost of generation in Kentucky, we utilize the cost of a Combustion Turbine as indicative of the marginal cost of capacity.

The estimate of the marginal cost of energy used in this report is based on confidential data from a number of utilities. The same marginal cost for peak and off-peak hours in Kentucky is used for both IOUs and COOPs. The marginal cost of capacity is added to the marginal energy cost.

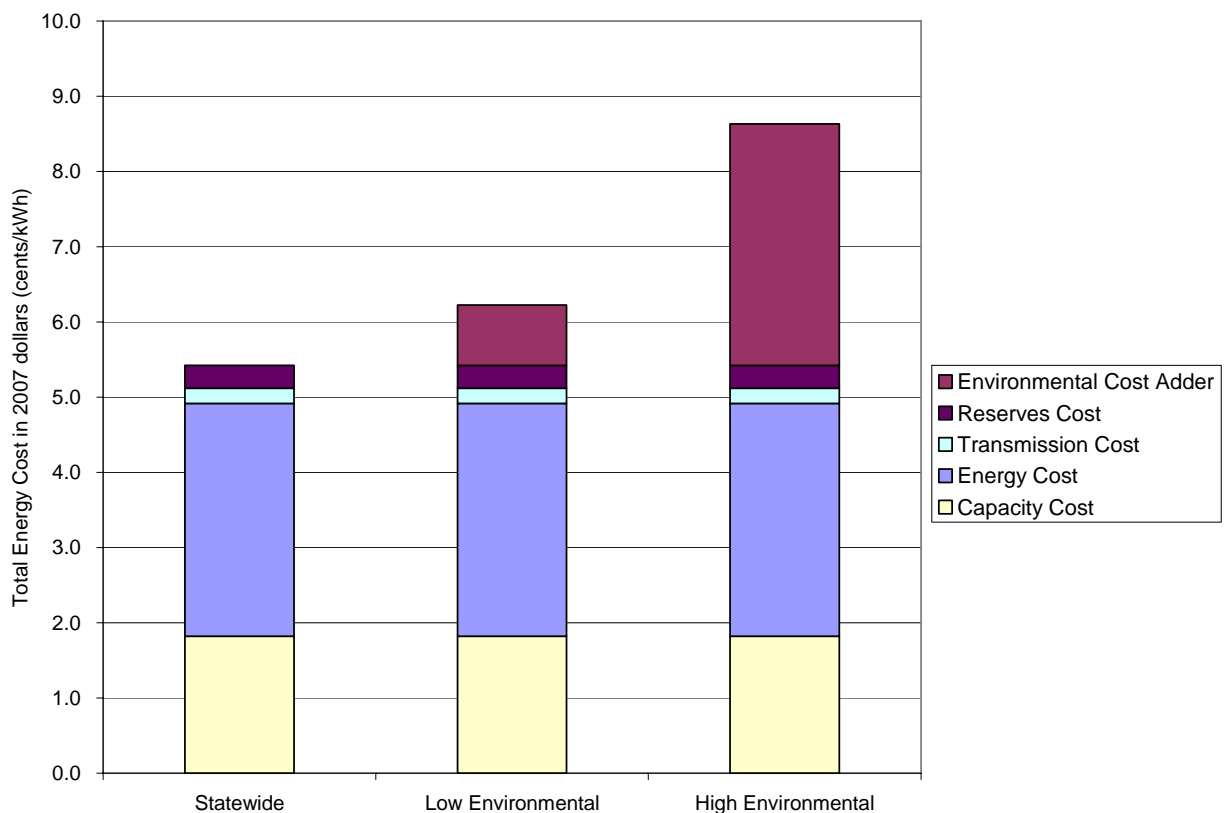
### ***Impact of Environmental Policy on Electric Costs***

Looking forward, the potential for a federal climate change and greenhouse gas policy is increasing. There are a number of different proposals being presented in Congress, but all will significantly impact fossil-fuel based generation costs.<sup>17</sup> Other environmental concerns also may increase electric costs. We have made rough estimates of the potential cost of such regulations. There is a range from low to high cost. For the estimate of the potential rate impacts and the consequent change in energy and peak load, we have utilized the high estimate of the cost of environmental regulations (High Environmental).

#### **Carbon Policy Cost**

At least four different Greenhouse Gas Reduction Bills have been introduced in Congress this past year. While the ultimate goals differ, all the proposed legislation are relying on a cap-and-trade program with decreasing caps that will directly impact the electric industry. The programs' beginning year range from 2010 to 2012, with the latter being a more realistic timeframe to put appropriate rules in place. Previous studies of various bills show estimates of carbon costs ranging from about \$5 to \$25 per ton of CO<sub>2</sub> at the onset, but growing to about \$7 to \$50 per ton after 10 years (in 2005\$). In the graph below, we demonstrate the impact to Kentucky energy costs if carbon costs are \$10 and \$40 per ton for a representative year. This reflects a 15% to 65% increase in marginal cost of energy.

<sup>17</sup> "Climate Change: Greenhouse Gas Reduction Bills in the 110<sup>th</sup> Congress," CRS Report For Congress, January 31, 2007.  
<[http://opencrs.cdt.org/rpts/RL33846\\_20070131.pdf](http://opencrs.cdt.org/rpts/RL33846_20070131.pdf)>

**Figure 5: Estimated 2012 Marginal Cost of Energy**

Since the cost of electricity varies by season and by hour, and we want to examine the impact of seasonal and time-differentiated pricing, we present estimates of average state-wide rates based on marginal cost for a peak season<sup>18</sup> and for peak hours during the peak season. This enables us to estimate, in Task 1D, how much the current rates might change under different ratemaking structures.

<sup>18</sup> We assume that the peak season would be the three summer months for the IOUs, but would also include the three winter months for the COOPs.

Figure 6: High Season Marginal Cost Based Rate

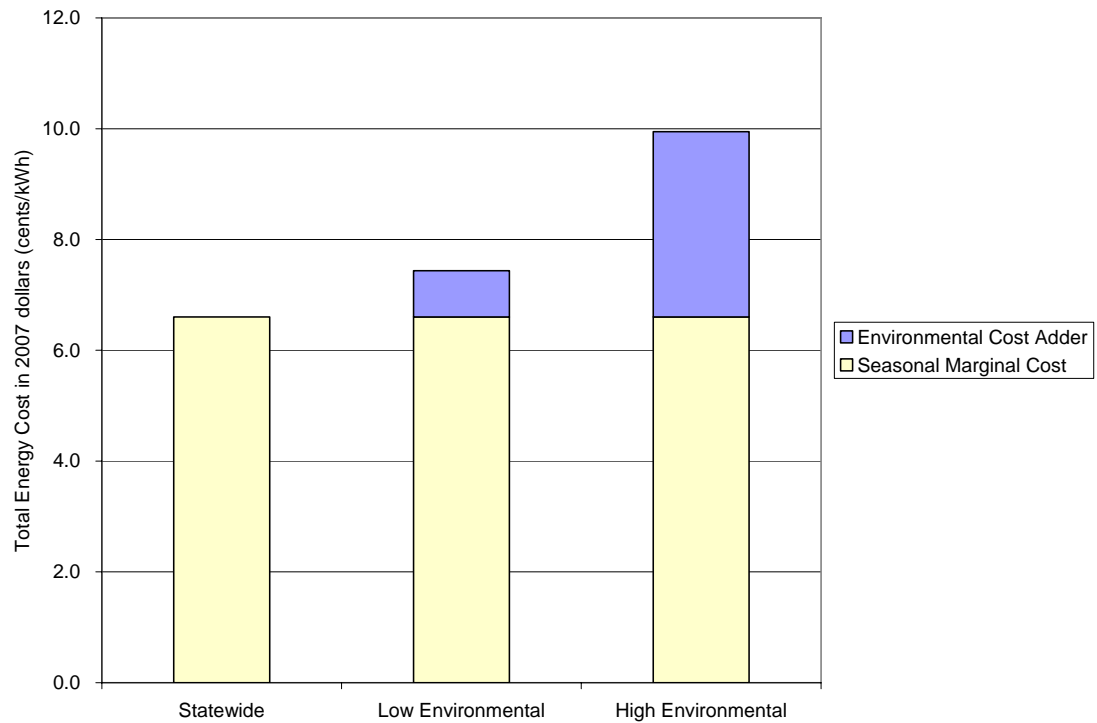
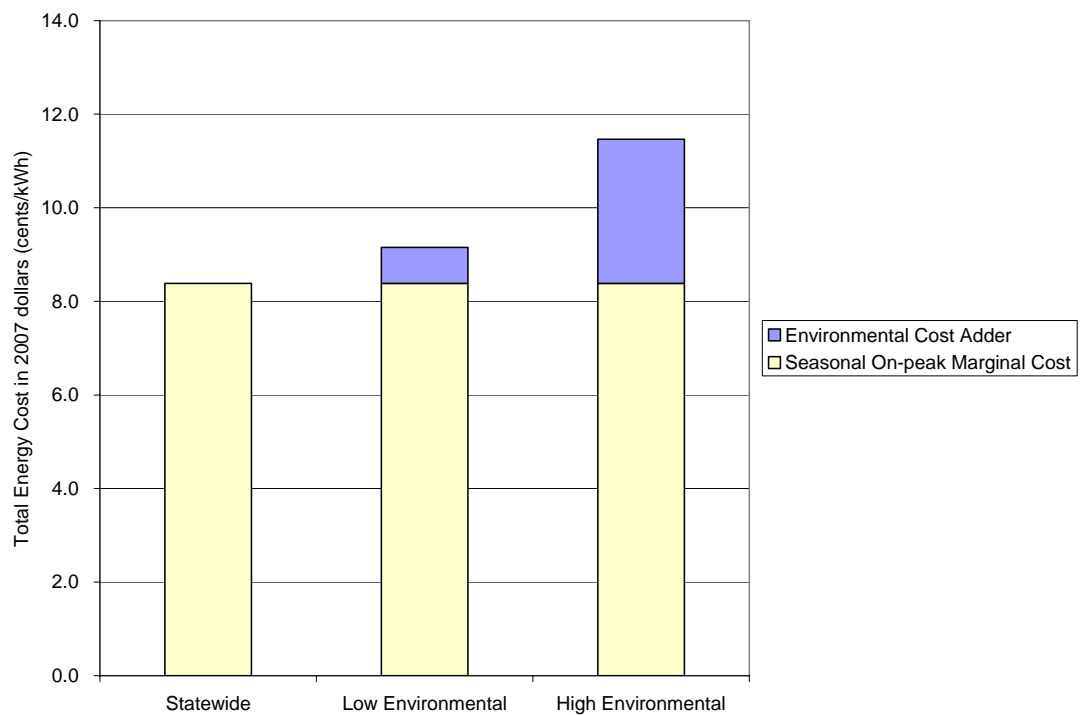


Figure 7: High Season Peak Period Marginal Cost Based Rate



**TASK 1C: Alternative Rate Structures**

There are alternatives to the standard rate structures described in Section 1 C that may provide more effective price signals in terms of encouraging additional energy efficiency. These are described below.

***Seasonal Rates***

A common variant to the standard rate structures are rates that vary by season. The seasonal differential is designed to reflect higher energy costs and/or higher capacity costs in certain seasons. Which months and seasons cost more and which less are determined by the utility's load shape and cost profile. Most commonly today, we find summer peaking systems driven by air conditioning. Energy costs tend to be higher in the summer. Since increases in the existing summer peak are likely the drivers behind any need for new capacity, summer capacity costs are also higher. There are some utilities that are winter peaking (driven by heating loads), and others whose winter and summer peaks are similar. Rate structures that reflect these seasonal differences inform customers that using power in the peak period is more expensive than at other times.

***Increasing block rates***

In this type of rate, customers pay one charge for usage (i.e., per kW or per kWh) up to some amount, and a higher charge for usage above that amount. The cutoff between the two rates is generally set at a number that results in most customers using more than the lower block amount. This enables the higher rate to be applied to the most discretionary (i.e., marginal) customer use. This rate may be

useful in situations where the cost of additional output is greater than average cost (marginal cost is greater than average cost), such as when increasing use means the utility must use more of a more expensive fuel source. Increasing block rates are intended to let customers know that it is expensive to increase use, while not charging more than average cost for total use. It has been most common to utilize increasing blocks in energy charges, although the same concept can also be applied to demand charges.

**Declining Block Rates**

Earlier in the development of the electric industry, the more electricity that was generated, the lower the supply cost was per unit. Many utilities adopted a rate structure called declining block rates. With these rates, as the customer used more electricity, the price per unit would drop. Today, the marginal or next unit of energy that is purchased will cost more. Therefore, declining block rates can send a false signal to the market and discourage investment in energy efficiency. At least some cooperatives in Kentucky offer declining block rates for commercial and industrial customers.

***Rate structures with more emphasis on demand***

Rates structures in which much of the bill is collected through demand rates will create an incentive for customers to reduce their own peak use. Thus adding a demand charge to a rate, or increasing the amount charged for peak demand, will encourage customers to

reduce their peak usage. However, only if customers' normal usage pattern is very coincident with the system pattern will these rates accomplish much in terms of limiting peak usage. There have been utilities that have voluntary or mandatory demand rates even for small customers. For instance, such rates have applied to residential electric heating customers in winter peaking systems. The theory would be that most residential customers turn up the heat at the same time and so drive the system peak; if residential heating customers reduce their peak load, they will probably also reduce the system peak. This rate is described primarily in the interests of completeness, as changes in metering costs make this alternative less reasonable today. For close to the same metering cost, utilities can install smarter meters, which can accomplish more than can simple demand meters. It would not be cost effective to introduce this rate design today.

### ***Rate Structures to Further Demand Reduction***

Some utilities offer curtailable and interruptible rates through contracts, usually to larger customers, in exchange for their willingness to decrease their demand when requested. Usually a penalty is established if the curtailment or interruption does not take place. These rates give utilities a way to manage loads during emergency situations. Such rates are increasingly being used to manage loads for economic reasons. The rates also allow businesses to benefit from the efficient operation of the overall system.

Most recently, with increased interest by consumers in building on-site generation (e.g. solar photovoltaic, wind, and combined heat and power systems), net metering has become a rate option available to consumers. Typically with net metering, customers who own generation receive a credit for a portion of the energy they produce in excess of their consumption, which can later be used to offset periods in which they are consuming in excess of on-site generation. In this way, their generation can help reduce the capacity and energy that a utility may have to provide to serve its load.

### ***Time differentiated rates***

Time differentiated rates will also further demand response. There are a number of ways in which rates can be differentiated by time of use. These rate forms have existed for at least 30 years, under the rubric of Time of Day ("TOD") or Time of Use ("TOU") rates. Time-differentiated rates charge different prices depending on time of usage; all true time differentiated rates require more than standard metering. These rates provide customers better information about the true cost of incremental usage. Better price

#### **Example: Air Conditioning and TOD**

For example, if a customer pays 7 cents per kWh for electric use, they will use air conditioning at any time when they want it cooler. If it costs them 14 cents per kWh from 9am to 8pm and 5 cents in other hours, they can cool more in the low-cost hours and less in the high-cost hours, or install equipment that will manage their air conditioning to reduce costs.

#### **Example: Air Conditioning and Load**

Consider the same air conditioning customer discussed above. If the high peak period is from 1 to 5 PM, cooling more before 1 in order to reduce air conditioning use is easier to accomplish than during the two-period example.

signals contribute to energy efficiency, as customers themselves can make better choices if they have better information. The federal Energy Policy Act of 2005 encourages states to consider instituting time-differentiated and other rates that can encourage demand response and reduce total energy costs. Kentucky IOUs have time-differentiated rates but only for large customers, and as noted later, they may not be priced appropriately. A number of states, particularly those with higher cost electricity, are moving toward rates for all classes that will further demand response.

There are a number of options for time-differentiation of rates, increasing in metering and administrative costs and in accuracy. These include:

- Differentiation of prices by fixed periods
- Critical Peak Pricing
- Real time pricing

#### Metering for TOU

Metering requirements for any time-differentiated pricing are more expensive than standard metering. However, in recent years the incremental cost has been falling. For non-demand meters, the cost is less than double the cost of non time-differentiated meters. Switching to time differentiated metering also requires changes in utility billing and record-keeping, usually requiring significant information system expense.

Most existing time differentiated rates only distinguish between a peak and an off-peak period, which have been determined by analysis either of the utility's costs or its load.<sup>19</sup> We might find that the average marginal cost in the peak period is higher than the average marginal cost in the off-peak period by about 3 cents/kWh. Typically, during the off-peak period hourly marginal costs are set by baseload resources and do not vary greatly. There is more variation in hourly marginal costs during the on-peak period. In summer peaking systems, there is usually a high peak period in the afternoon, which is driven by air conditioning load. If costs are calculated and rates charged separately for the high peak period, marginal costs in this period might be 6 cents higher than in the off-peak period and 2 cents higher than in the moderate peak period. This critical peak or super peak pricing creates both more incentive for customers to switch load, and more opportunity.

Many utilities have offered time of use rates to customers on a purely optional basis. Optional rates will tend to attract customers who already have more than the typical ratio of off-peak to peak usage. If the rate is voluntary, peak/off peak usage will be a result of this customer self-selection as well as load shifting from more expensive to less expensive periods. In other words, although customers on voluntary time differentiated rates may use a higher proportion of energy off-peak than other customers, this may not reflect a change in usage due to the rate. Mandatory time-of-use rates are likely to cause customers to deliberately shift load, especially large customers who have more load that can be shifted. Customers who use very little electricity will tend to have little ability to shift load, so one rate design alternative is to make time of use rates mandatory only for relatively large customers. In Connecticut, for instance, which is making a great push for

<sup>19</sup> There is usually a very high correlation between increases in load and increases in costs by hour.

demand response, utilities have been moving toward mandatory time of use rates, introducing them first to the largest customers.

KU and LG&E will be implementing a Responsive Pricing and Smart Metering pilot program (Case No. 2007-00117) for residential customers. This time-differentiated pilot rate should provide information about how Kentucky-specific residential customers will respond to rate structures that better reflect marginal costs.

### *Real Time Pricing*

Real Time, or dynamic pricing, informs customers of actual costs, usually on an hourly basis. Real time pricing should provide the most accurate price signal to customers, but it is also most complicated to implement and to communicate. There are very large customers who are and have been receiving either day ahead hourly prices or real-time prices and who can respond to these prices. Other means of providing information about real-time prices are provision of temperature data in areas that are very weather sensitive or signals which inform customers when prices are expected to be above some threshold level. Real-time pricing is most relevant in areas where hourly prices are determined by regional power markets with transparent electricity pricing, which may occasionally result in peak prices of \$2.50 per kWh and more. Real time pricing is probably not appropriate for Kentucky's system.

**TASK 1D: Impact of Rate Structure on Energy Efficiency****Comparison and Evaluation of Rate Structures relative to Energy Efficiency**

This task is aimed at answering the question of whether existing rate designs in Kentucky communicate appropriate price signals to incentivize customers to make cost effective energy efficiency choices, and at the impact that changes in rate structures is likely to have on electric usage in Kentucky. The analyses of changes in usage are based on aggregate data and are necessarily not precise.

***Existing flat rate structure***

The first question is whether the existing flat rate structure charges at least as much as average marginal supply costs. Based on a comparison of our estimates of marginal costs to residential rates<sup>20</sup>, the existing flat rates appear to be somewhat higher than average marginal supply costs. This is not surprising, since average rates recovery distribution costs as well as supply costs.

The second question is how flat rates will affect customer demand and energy efficiency when increases in fuel costs, capacity costs, and possibly costs resulting from carbon policy are included in rates. The existing rate levels and rate structures have been based on conditions that existed in the past, conditions that are changing.<sup>21</sup> If rate increases are greater than the rate of inflation (i.e. there is a real increase in the price of elasticity), this will have some dampening effect on electric demand.

If marginal costs increase, block rates might improve current rate design

Another question is whether these cost increases will cause marginal costs to rise more than average costs. If marginal supply costs are or become higher than the total average per kWh charge, flat rates will not signal to customers the marginal cost of supply. Rates could theoretically be redesigned to communicate the higher marginal supply costs. For instance, the introduction of an increasing energy block rate, as described in Section 1C, would communicate that higher usage cost more than average cost. This rate change should lead to somewhat more demand response than a simple increase in flat rates.

***Alternative rate designs can improve price signals and energy efficiency***

Even though current total rates appear to be as high as average marginal costs, this does not mean that current rates are providing appropriate price signals to encourage cost-effective energy efficiency. Rate design could do a much better job than the current rate structure in providing price signals regarding the cost of producing electricity. Fundamentally, marginal costs vary across months and across hours. An increase in load on a summer afternoon contributes to need

<sup>20</sup> Analysis of general service customers is much more complicated, and has not been performed.

<sup>21</sup> As an example of large changes in cost, LG&E & KU's Integrated Resource Plan of 2005 assumed price of oil was "...expected to remain below \$30 per barrel until 2010" (Staff Report on 2005 IRP in Case No. 2005-00162, p. 4)

for new capacity and causes expensive fuel to be burned. An increase in load in the night in a mild spring month does neither. Flat rates do not communicate this and therefore do not provide customers with the opportunity to respond to underlying marginal costs.

### *Increasing block rates*

For many rate classes, energy use above a base amount is likely to be primarily during peak periods. For instance, high residential use in the summer will tend to reflect air conditioning. If this is the case, one simple substitute for a time-of-use rate is an increasing block rate, whereby customers pay more for use above some base amount.

### *Seasonal rates*

The potential of this alternative rate design is discussed next, because it is relatively simple and does not require any metering changes. As described in Subtask 1A, there is essentially no seasonal differentiation in typical Kentucky electric rates and the only time-differentiated rates are voluntary rates which serve only very large industrial customers. Theoretically, this suggests that the existing rate structure is not communicating to customers the true cost of how they consume electricity.

Seasonal but non-time differentiated rates could provide better price signals than existing rates. Introducing seasonal rates would be a relatively simple matter, since it does not require any change in existing metering. The expected result would be some reduction in use during peak period use, but no load shifting within daily periods. We would expect limited shifting between periods in the short run. Customers might turn down the air conditioning or the heating<sup>22</sup>, but could do little else to reduce load during the expensive periods in the short run. In the longer run, seasonally differentiated rates will provide more incentive to purchase more efficient space conditioning equipment.

Seasonal rates for the IOUs should probably look different than for the COOPs, due to different load shapes, which are summarized below.

In general, the load patterns for the IOUs tend to be summer peaking; both demand and monthly consumption are greatest in the summer months. On the other hand, the COOPs' peak demands and monthly consumption are slightly higher in winter than in summer. We understand this reflects a higher proportion of air conditioning in the more urban and suburban areas served by the IOUs, and a higher proportion of heating load in the rural areas served by the COOPs.

These load shapes<sup>23</sup> illustrated in the figures below indicate that while summer rates should be higher than rates during the rest of the year for the IOUs, the picture is more complicated for the COOPs. Their peak period includes three summer and three winter months.

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<sup>22</sup> This response is obviously limited, as it will tend to decrease comfort levels. As noted in the discussion of elasticity, seasonal rate changes will probably not affect the usage patterns of very small customers and high income customers.

<sup>23</sup> Variability in load shapes is not identical as variability in marginal cost, but they are usually highly correlated.

Figure 8

## 2006 Utilities Monthly Peak Demand (Non-Coincident)

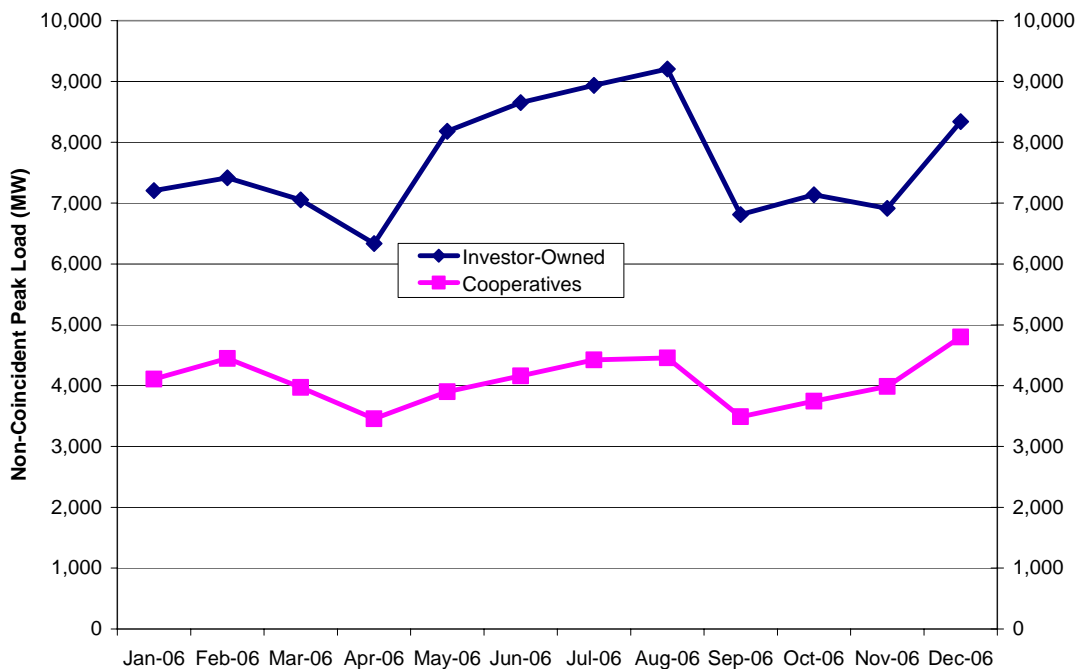
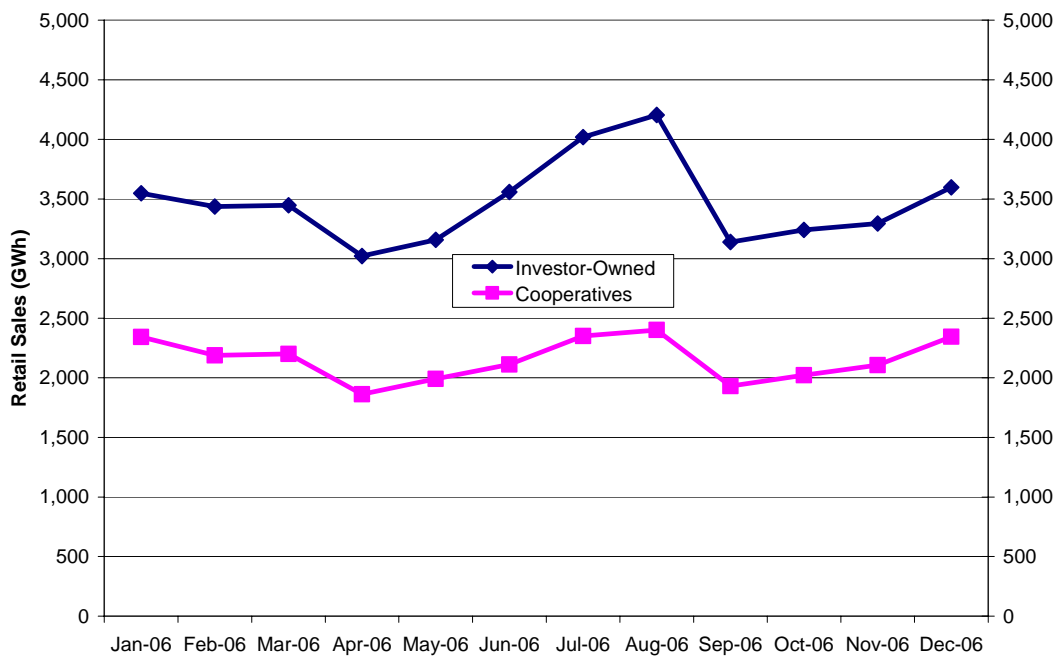


Figure 9

## 2006 Utilities Monthly Retail Sales



### *Time-Differentiated rates*

Time-differentiated rates can provide the most effective price signals, although they introduce more expense and complexity. They can be expected to improve the efficiency of use of the electric system by informing customers of the different marginal costs at different times. Many customers will respond, both in the short and the long run, by shifting load from more expensive to less expensive times.

#### Issues Related to TOU Rates

Introducing mandatory time-of-use rates raises a number of issues. The additional cost of metering must be considered and weighed against the potential savings in electric supply costs that can be caused by the rate change. In addition, there may be concerns about the bill impacts that could result from mandatory time-of-use rates. Time differentiation will increase some bills more than others, perhaps significantly so. Policy makers must make policy decisions between better price signals and bill continuity.

We have performed a number of analyses to estimate the impact that alternative rate designs could have on energy efficiency – both in terms of reducing load and of shifting load from more expensive period.

### *Modification to existing Time-Differentiated rates*

It was noted that the IOUs offer time-differentiated rates to larger customers. A fairly large amount of general service load is served on these rates. However, it appears that these rates understate even current on-peak marginal energy costs. The time-differentiation exists entirely in the demand charge. This should provide an incentive to customers to manage their peak load, but the energy charge appears to understate current on-peak marginal energy costs. A redesign of these rates may have the potential to induce more energy efficiency. One caveat is that research shows that industrial loads can have very low price elasticities, so the impact of price changes may be small.

## ***Analysis of the Impact of Possible Rate Design Changes***

Rate design has the potential to reduce load growth and to reduce peak loads. Customer response to rates can reduce the need for additional generation.<sup>24</sup> This analysis begins with a comparison of existing average rates for the major rate classes to estimated marginal costs. Marginal costs are portrayed on an (1) average annual basis; (2) on a seasonal basis; and (3) on a time-differentiated and seasonal basis.

It is one of the axioms of economics that the quantity demanded of a product normally changes inversely with change in real<sup>25</sup> price. That is, for most products, as price goes up, the quantity demanded goes down. This response will usually be greater the more time customers have to adjust to the change. This response is called price elasticity. For goods that are considered necessities, as electricity is in the U.S., price elasticities are relatively low. That means that if

<sup>24</sup> This customer behavior is called "Demand Response".

<sup>25</sup> Price adjusted for inflation; the price of the good or service compared to the price of average goods and services. Through the rest of this discussion, "price" refers to real price.

prices increase by 10%, the decrease in quantity demand is less than 10%, particularly in the short-run.

The first step in the analysis is to suggest what rates would be if based on alternative portrayals of marginal costs. We have modified full marginal cost rates to reflect the likely impact of revenue collection constraints.<sup>26</sup> The second step is to estimate the impact on electric use of changes in rates, based on expected price elasticities.

We focus on two types of price elasticity —“own price elasticity” and “elasticity of substitution”. The relationship between a change in the average price of electricity and the amount demanded is called “own price elasticity”. This is due to customers using less electric service, and, in the longer run, customers reducing usage through measures such as purchasing

more efficient appliances. Another type of elasticity is “elasticity of substitution”. This type of elasticity estimates the relationship between an increase in price in some hours and a decrease in price in other hours on the use in those periods. This involves customers shifting use of appliances from the high cost hours to the lower cost hours. There has been a great deal of recent research on price elasticity with regard to electricity, and we have relied on that research.

Our estimate of marginal cost shows that a environmental regulations could increase marginal costs significantly. It would also cause a lesser increase in average costs. Communicating the marginal cost to customers would probably require adoption of an increasing block rate.<sup>27</sup>

We have made rough estimates of the impact of seasonal rates on energy consumed by the residential class during the seasonal peak period (all-hours during peak months) and of the impact on peak usage. Under this rate, customers pay somewhat more for energy during the peak season for the IOUs or seasons for the COOPs.

#### How the elasticity calculation works

Suppose that price elasticity for a product = (-0.5). Some individual customers will respond more, and some less, but this represents the typical customer price elasticity. If the price of the product increases by 50%, we multiply the elasticity times the percentage price increase – and find that customers in general are expected to purchase 25% less of the product because of this increase.

#### Estimates of Residential Price Elasticity

Based on the average of 58 recent studies of “own-price elasticities” in California and in the U.S., the short-term elasticity was estimated to be (-0.12) and the medium-term elasticity was (-0.28). This means that a 50% increase in rates, for example, may decrease consumption 6% in the short-term and 14% in the medium-term.

Estimates of residential “elasticity of substitution” range from (-0.1) to (-0.19) derived from 14 different experiments, with a pooled estimate of (-0.13). This would imply, for example, if rates were 50% higher during on-peak hours, there would be a shift of 6.5% of usage during on-peak hours to off-peak hours.

To be conservative in this analysis, we have assumed an own price elasticity of (-0.12) and an elasticity of substitution of (-.13).

<sup>26</sup> By this we mean that flat rates set to equal estimates of marginal costs might cause non-peak monthly rates and off-peak hourly rates to decrease so much that the utility could not collect full revenues. We have accordingly moderated the full marginal cost rates where necessary.

<sup>27</sup> Because if the marginal cost were charged to all usage, the utility would over-collect its revenue requirement.

We have also estimated the impact on system peak load of a rate that is both time-of-day and seasonal rate for residential customers. Under this rate, customers pay an even higher rate for use during peak hours in the peak season. It is more difficult to estimate the impact of time-of-day rates for commercial and industrial customers, as there is a wider range of elasticity estimates, and as some of these customers are already served on time-of-day rates.

### **Residential Results**

We have estimated the potential impact on residential load of various types of rate changes. Seasonal rates, based on seasonal marginal costs, will result in reduction of load during peak seasonal periods. Time-differentiated rates will reflect even higher marginal costs during peak hours. This will result in shifting of load from more expensive periods to less expensive periods, and will probably also cause a reduction in total load. Higher rates during summer and winter peak hours will provide an incentive to customers to purchase more efficient heating and cooling systems. We also estimate the impact on load of introducing increasing block rates, in which the tailblock was set at the marginal cost that would result from the high environmental cost case. These estimates are summarized below:

Table 2: Summary of Results from Various Rate Designs for the Residential Class

<b>Seasonal Rates</b>	<ul style="list-style-type: none"> <li>Seasonal rates set at marginal costs (without environmental costs) could decrease residential peak season load, by 1% to 2%.</li> <li>Seasonal rates set at marginal costs reflecting our high estimate of environmental costs could decrease residential peak season load by 2% to 3%.</li> <li>Reductions in demand (MWs) may be somewhat less than the estimates of reduction in loads (MWhs).</li> </ul>
<b>Time-differentiated Seasonal Rates</b>	<ul style="list-style-type: none"> <li>Time-differentiated seasonal rates could decrease residential peak period loads by about 8% and 9%.</li> <li>Time-differentiated seasonal rates reflecting our high estimate of carbon costs could decrease residential peak period loads by as much as 10%.</li> </ul>
<b>Tailblock Rates</b>	<ul style="list-style-type: none"> <li>Tailblock rates set at marginal costs reflecting our high estimate of carbon costs.</li> </ul>

These estimates must be accompanied by some important caveats. One is that these responses will not be instantaneous. While customers can take some actions quickly, it will take time for the purchase of more efficient appliances to have an impact and for customer behavior patterns to change significantly. In addition, price elasticities are the product of complicated analyses of customer behavior, and thus are not expected to be perfectly accurate.

To actually make such rate changes, utilities would work with their own actual data on load shapes and would also need to adjust rates so that they would collect the correct revenue requirement.

***General Service and Total Results***

The potential impact of rate redesign on general service (commercial and industrial, or C&I) customers is more questionable than the impact on residential customers. While larger customers have more load that can be shifted, the research also shows that price elasticities for industrial customers are fairly low and also quite variable. Some types of general service customers have very little ability to reduce or shift load while others have much more ability, particularly in the longer-run.

Research on commercial and industrial customers shows that time-differentiated rates appear to create some reduction in total load, as the decrease in load during the expensive periods does not all result in a corresponding increase in load during the less expensive periods.

It appears that seasonal rates could reduce C&I load but the impact is likely to be small. Rates that are both seasonal and time-differentiated rates could reduce peak period C&I load by 6% to 12%, because peak period rates, even that do not reflect high environmental costs, will be considerably higher than current average rates.

Overall, rate changes could possibly decrease loads and peak loads enough to postpone the need for new capacity in Kentucky for one or more years.

## TASK 2: ALTERNATIVE RATEMAKING METHODOLOGIES

### ***Task 2 A: Kentucky's Traditional Ratemaking Process***

#### ***Description of Kentucky's Traditional Ratemaking Process***

The ratemaking process in Kentucky exhibits three essential steps that are integral to ratemaking in jurisdictions across the country. These steps include:

- 1. Revenue Requirements:** This initial step focuses on identifying the costs that each utility incurs in providing service, so as to determine the total revenues that must be recovered from ratepayers to ensure that those costs are covered and a fair profit is earned;
- 2. Cost Allocation:** This second step encompasses allocating the costs that each utility incurs in providing service among the different customer classes, so as to establish the levels of costs (and thus the associated revenue requirements) that each customer class is causally responsible for; and
- 3. Rate Design:** This third step focuses on calculating rates that (a) provide each utility with a reasonable opportunity to achieve its revenue requirements, and (b) implement various public policy objectives.

This Section addresses each of these steps, particularly as they relate to the challenge of establishing a rate structure that is likely to promote investments in demand-side services.

#### ***1. Revenue Requirements***

The process by which revenue requirements are determined for Kentucky's utilities is well-established in the practices and precedents of the public utility commission. In order to remain a viable, ongoing concern in the delivery of essential services, each utility must receive sufficient revenues from its customers to cover its costs and provide investors with reasonable returns on invested capital. Determining the revenue requirement for each Kentucky utility involves the identification of costs for a historic "test year." These costs include fuel and variable operating and maintenance expense, and other expenses, including depreciation. They also include profits, which are calculated as a return on the utility's rate base. The revenue requirements portion of a rate proceeding typically includes consideration of the full range of operating expenses and capital costs. By applying standards of "prudence" and by requiring showings that various expenditures can withstand scrutiny under "least cost" expectations, the Commission examines both favorable and unfavorable changes at the same date, and determines what level of revenues is necessary for the utility to recover its costs and earn adequate profits based on a consistent view of costs.

Note that the revenue requirement includes a return, which provides compensation to stockholders and bondholders for the capital that they put at risk in financing operations. The Commission determines an appropriate allowed return on equity, and a total rate of return is calculated by combining the return on equity with return necessary to cover debt costs and

income tax. Allowed earnings are determined by applying the rate of return to rate base, primarily investments in utility plant.

Although the rate case normally examines all costs and sets “base rates” until the next rate case, in Kentucky, utilities can essentially “true up” for their fuel costs after base rates are set, as noted below.

## ***2. Cost Allocation***

Once the increase in revenue requirement over existing revenues for a given utility has been established, the ratemaking turns to the task of designing rates to bring in the necessary level of revenues. The underlying concept here is that rates should be designed so that customers pay for the costs that they impose in the utility's system. It is necessary to determine how much to collect from each rate class. This is usually based on the class cost of service, but the specific class revenue targets will also be influenced by such other considerations of how much increase from existing rate levels is appropriate.

## ***3. Rate Design***

Once a utility's revenue requirements have been established and a class revenue targets are set, rates are developed to collect the class revenue target from expected sales. To take the simplest rate design, the revenue target would be divided by expected sales volumes.

### ***Rate Riders***

The Kentucky Public Service Commission has approved a number of special rate riders to supplement the base rates that are developed and implemented through the process described above. Such riders would result in rates “tracking” certain costs. These riders track fuel on a monthly basis, and also track Demand Side Management costs.

### ***Ratemaking methodology and Utility Earnings***

Once rates have been set through this process, the utility will earn the rate of return projected in the rate case **if** its expenses, net book value of plant, interest cost, number of customers, and sales remain the same as the projections used to develop the rates. Of course all of these components never stay the same. Some changes, such as fuel, do not create problems, because of the fuel adjustment rider. Changes in numbers of customers and in sales volumes create higher or lower revenue than projected.

***TASK 2B: Assessment of the Benefits and Drawbacks of the Current Ratemaking Methods******Benefits of the Standard Methodology***

In the standard methodology, rates are set after a thorough investigation of all costs, revenues, and sales. Usually the process begins with a review of actual booked values, but adjustments may be allowed for known changes to those values. The process aims for consistency in the time period for which costs and revenues are reported. Rate design is based on a consideration of all rate objectives, including determination of appropriate price signals. Customers know what their rates will be, except for such changes that flow through the various riders. The allowed rate of return is based on an assessment of the risks that the utility has historically experienced and observed changes in the electric industry. The utility can improve its profits until the next rate case through more efficient management of its costs, or if its sales increase faster than costs increase.

***Drawbacks of the Standard Methodology Regarding Energy Efficiency***

- Utilities have incentives to increase their rate base
- Utilities have no incentive to use demand-side resources
- Utilities have incentives to increase sales

Section 2C will focus on the three drawbacks of the standard methodology that may interfere with energy efficiency. From the standpoint of the utility, once rates have been set, its earnings depend on not only on its management, but also on sales volumes,<sup>28</sup> over which it has no control. If sales go down, revenues will decrease. Earnings may not fall, if costs decrease at the same rate as revenues, but a decrease in sales will mean that earnings will be less than they would have without the sales decrease. If sales increase, its revenues will increase. The utility has little or no control over a number of factors which cause its sales to decrease, such as economic conditions, weather, or customer-initiated energy efficiency. However, it does have control over its own Demand Side Management programs. If its programs decrease sales, its revenues will decrease, often with no offsetting decrease in costs. Even if such programs should decrease total long run costs, in the short run they can decrease utility earnings. It is often argued that traditional ratemaking does not provide efficiency incentives, since utilities can normally collect all of their incurred costs. However, once rates have been set, the utility can increase its earnings by reducing its costs.

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<sup>28</sup> Earnings also depend on the number of customers, but for this discussion we will assume no change in the number of customers.

***TASK 2C Alternative Ratemaking methodologies***

All of the alternative methodologies begin with a regulatory review of the utility's costs. However, except for the Future Test Year methodology, the intent is that there will be some type of formulaic future adjustment to rates. These variants of ratemaking are advocated on the basis of being simpler (as opposed to changing rates only after full rate case proceedings) and providing better incentives to utilities for improving efficiency.

***Future Test Year***

This is basically a variant of the standard ratemaking approach, except that the utility projects costs and sales to a future year or years. If costs are based on expectations for the next year, it is appropriate that revenues and sales are based on a projection of the same year. If the utility has been experiencing or expects to experience sales decreases because of either customer-initiated energy efficiency or its own DSM programs, this decrease would be reflected in its projections. If the forecasts of future costs and sales were correct, the utility would earn the approved amount even though its sales decreased.

***Performance Based Ratemaking***

The basic concept of performance based ratemaking is that the utility is allowed to automatically adjust rates based on a formula that is supposed to reflect inflation and productivity increases. These formulae can be very complicated, but under the simple version the utility's earnings will decline from what they would have been if sales decrease.

***Earnings Sharing Mechanism***

This methodology also begins with a standard review of utility costs, but then allows or requires automatic rate adjustments if reported earnings increase or decrease beyond some approved limit. This would mean that if sales decreased enough to reduce the utility's earnings below the limit, it would be allowed an automatic increase. This method can also be very complicated. It was utilized for several years in Kentucky and was subsequently rejected.

***Decoupling In Its Various Forms***

Decoupling refers to a ratemaking methodology that "breaks the link" between utility earnings and sales volumes. The starting point for decoupling is still rates that are determined based on the standard ratemaking methodology, so that rates are set to collect an approved revenue requirement. The difference between this and the standard methodology is that it is not rates that

are fixed until the next rate case, but rather the utility's fixed revenue.<sup>29</sup> There are a number of ways that this decoupling can be accomplished.

<b>Version 1</b>	Collect most revenue through fixed charges – utilities particularly advocate for this method for distribution revenues <sup>30</sup>
<b>Version 2</b>	Set revenue per customer (often for gas utilities) – if this declines, rates are adjusted upward until the same revenue is collected. If the number of customers increase, the total revenues can increase.
<b>Version 3</b>	Set weather normalized revenue per customer. Each year, estimate weather normalized revenues, and if the revenues decline, adjust rates upward until same revenue is collected. This approach could also reduce rates if revenue per customer increases because of increases in usage. Again, utility revenues can change with the number of customers.
<b>Version 4</b>	Set fixed revenue total; each year, adjust rates upward if this revenue has been under collected, downward if this revenue has been over-collected.
<b>Version 5</b>	Estimate what sales growth (per customer or in total, weather normalized or actual would have been in absence of decoupling - if this declines, adjust rates upward until same revenue is collected. In areas where load is growing, this is the approach that utilities are most likely to advocate –it attempts to put them in the same revenue position they would be if sales per customer continued its expected trajectory without additional energy efficiency.
<b>Version 6</b>	Combine decoupling and automatic changes in allowed revenues; estimate what future revenue per customer should be based on various adjustments to the revenue per customer calculation determined in the base rate case; these adjustments may reflect capital investment, and increases in expenses, so that even if use per customer does not decrease rates could increase.

The major experience in decoupling has been with natural gas local distribution companies. There has been a fairly strong trend of reduced use per customer of natural gas for a number of years, as major appliances using gas have become more efficient. The impact of improved efficiency from gas appliances has overwhelmed other influences on the use of gas. Most states now have tracking mechanisms that allow gas utilities to recover all of their supply costs, so this reduced use per customer is the reason why gas utilities need to file rate cases. As a result, a number of states have adopted gas decoupling mechanisms that provide utilities with automatic rate increases as weather normalized use per customer declines.

For both gas and electric utilities, decoupling is usually on a customer class basis, since use per customer varies greatly between classes. If decoupling were based on an average revenue that was not class specific, if a utility lost a big industrial customer, its average use per customer could decline significantly even though there would have been no energy efficiency involved.

There are many fewer states that have utilized decoupling for electric utilities. Several states utilized then rejected electric decoupling after a few years of experience with it. These include Maine, Oregon, Washington and New York. Decoupling was discontinued for various reasons,

<sup>29</sup> Excluding fuel and purchased power costs.

<sup>30</sup> High fixed charges mean low volumetric charges; the price per kWh no longer providing as much an incentive to conserve, so that the utility's disincentive has been removed, but customer's incentive has been reduced.. We will not consider this version of decoupling in the following analysis.

including significant rate increases, and restructuring of the electric industry in the state. In most areas, electric use per customer has been increasing. In these areas, DSM programs might reduce the rate of increase, but electric utilities may not actually experience reductions in usage as a result of DSM programs. States that do have electric decoupling mechanisms in place currently include: California, Idaho, New York, and Maryland.

### ***Does Decoupling Address the Drawbacks That May Result From the Standard Ratemaking Methodology?***

The primary focus of this section is whether an alternative ratemaking to the current ratemaking methodology, specifically Decoupling, can change the three incentives that may impact utility support for energy efficiency in Kentucky. This section also addresses other impacts on utilities and ratepayers that would or could result from adopting the decoupling alternative.

#### ***Incentives for utility to support sales growth***

It is generally true that increases in sales per customer will increase earnings. This leads to the expectation that utilities under traditional ratemaking will be eager to increase sales, whereas Decoupling may eliminate the advantage of higher sales. Thus there is concern that utilities will encourage load growth, even when load growth may increase costs. How significant this is depends on whether utilities have much opportunity to increase sales per customer. If regulators do not allow advertising and do not allow rates that promote additional use, there may be little such opportunity.

#### ***Disincentive to utility DSM programs and Ratemaking methodology***

Decoupling advocates have argued that under traditional regulation a utility's earnings are "entirely dependent on meeting or exceeding expected sales volumes"<sup>31</sup>. This is overstated; utility earnings will be dependent on a number of other factors, such as whether they can meet or beat expected cost projections. However, it is generally true that in the short-term sales reductions will reduce earnings and sales increases will increase earnings. This leads to the expectation that utilities under traditional ratemaking will not support energy efficiency measures that reduce sales. This same reasoning may not apply to programs that cause load shifting but not load reduction.<sup>32</sup>

While utilities may have a disincentive to support programs that reduce load, they will usually not have the same objections to load shifting.<sup>33</sup> If total load remains approximately the same, revenues may not decrease, but load shifting may actually decrease power costs<sup>34</sup> and increase reliability.

In the standard methodology, achieving expected revenues depends on actual sales equaling the projected sales levels which were the basis for the rates. If the projected sales account for the

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<sup>31</sup> Bachrach & Carter, NRDC, p. 5-4.

<sup>32</sup> If rates are time-differentiated, shifting load to less expensive off-peak periods will reduce revenues, and may also reduce earnings.

<sup>33</sup> If rates are time-differentiated, shifting load to less expensive off-peak periods will reduce revenues, and may also reduce earnings.

<sup>34</sup> If fuel and purchased power costs are tracked and reconciled through a rate adder, utility profits will be neither worsened or improved by load shifting.

impact of DSM programs, then the utility's earnings would be as projected. This is one "fix" — an adjustment to sales volumes.<sup>35</sup> Of course, the utility would still be better off in terms of earnings if its programs did not produce the projected reductions in sales.

Kentucky has taken an alternative approach to this disincentive problem under traditional regulation. The utilities' approach to energy efficiency programs will be affected by the Lost Revenues component of the DSM rate riders. If the utilities institute a new energy efficiency program, they can estimate how much it will reduce sales and how much that sales reduction will reduce revenues. This revenue "shortfall" will be collected through the DSM rate rider.

The existing DSM riders should serve to remove the utilities' disincentive to instituting their own DSM programs. Thus in Kentucky the combination of traditional ratemaking plus the DSM rider means that with the current methodology utilities should not have a disincentive to support DSM programs. There may be some exception to this if the lost revenue component of DSM rider is incomplete. Generally the complaints regarding lost revenue computations is that they may favor utilities, providing more than the actual lost revenue, and they add complexity to ratemaking. However, utilities may still be negatively affected by energy efficiency that does not result from their own programs, because they receive no "lost revenues" adjustment for energy efficiency that is unrelated to their programs. Proponents of decoupling argue that with DSM riders utilities have an incentive to overstate the energy savings that result from their programs.<sup>36</sup> It is clear that using DSM riders requires effective regulatory oversight.

### *Do utilities have a positive incentive to encourage energy efficiency?*

It has been posited that utilities may oppose DSM programs and energy efficiency in general because they may prefer adding rate base to reducing the total cost of electric supply through investing less and spending more on DSM. Thus even if they do not lose revenues because of energy efficiency<sup>37</sup>, utilities will usually find building generation more profitable than reducing demand. Energy efficiency does not automatically increase rate base the same way that building generation does. To the extent that this motivation is a problem, decoupling does not solve the problem. Explicit incentives for energy efficiency programs or penalties for failure to institute cost effective programs may be necessary. This would be true under the current methodology and also under the decoupling methodology. Decoupling should remove any disincentive that results from decreasing revenues, but does not create an incentive to encourage energy efficiency.

Incentives could take several forms, such as a return on investments in energy efficiency, or a higher reward return for meeting efficiency goals.<sup>38 39</sup> These incentives can only be used if state laws regarding regulation allow them. Regulators may have the authority to order energy efficiency programs as contributing to the public good, and to penalize utilities if they do not comply. Offering either an incentive or a penalty associated with energy efficiency will require an additional regulatory task, that of monitoring energy efficiency performance. Once the

<sup>35</sup> This will only be a solution for the period of the sales projection — usually only the next year.

<sup>36</sup> If program savings are overstated, it would seem that more programs would pass screening tests.

<sup>37</sup> For instance, if a lost revenues provision in their tariff compensates them for lost sales due to their programs.

<sup>38</sup> EON's most recent DSM program requests that it receive an "incentive" revenue of 5% above program costs.

<sup>39</sup> For instance, Massachusetts includes in utility revenue requirements an 8% adder to DSM programs.

utility's energy efficiency strategy were determined, both incentives and penalties could assist in causing the utility to implement that strategy

#### Utilities' Perception of Energy Efficiency

All of this discussion has implicitly assumed that energy efficiency will simply decrease earnings and therefore be negatively perceived. This is not always and completely the case. If growth in load means that utilities must invest, which may mean an increase in rates and a decrease in credit rating, there may be strong public and possibly regulatory resistance to this path. In this case, the utility may face of disallowances or higher credit costs if it builds capacity than if the utility avoided the need for the additional capacity by encouraging energy efficiency.

We note that energy efficiency instituted by customers directly, unrelated to utility programs, may also reduce utility profits below what they would have been. Decoupling will remove this impact, even though the cause of the load reduction was not utility action. To the extent that the rate design changes that were discussed in Section 1D reduce revenues more than costs, utilities may argue against such rate changes. Decoupling would remove this reason for objecting to such rate changes.

### ***Evidence Regarding Impact of Decoupling Methodology***

Decoupling of gas revenues and sales has been around for awhile. Ten states have gas decoupling in place, and a number of others may be adopting decoupling. It appears that decrease in gas use per customer was a cause of decoupling. It is not clear how much decrease in use per customer was the result of utility DSM programs, or whether DSM programs were introduced or expanded in the decoupled states because of decoupling, since there are at least 29 other gas utilities that have energy efficiency programs. Electric utility decoupling has been adopted by Idaho, New York, and Maryland within the last six months, so there is no information on the results of this change in ratemaking methodology.

California has utilized a form of decoupling for a number of years. Their method is what was described as Version 6, which is called the Electricity Rate Adjustment Mechanism, or "ERAM". Utilities are essentially guaranteed not that they will collect the total revenues that were allowed in a rate case, but that they will collect a revenue per customer amount. The allowed revenue per customer is not fixed, but changes each year, reflecting complicated cost adjustment mechanisms. Advocates of decoupling point to California experience as evidence that decoupling contributes to energy efficiency. Use per customer in California has barely increased compared to use in the rest of the country over the last thirty years. However, California has a number of other unique characteristics that may explain why customer use has not grown compared to the rest of the country. First, California's rates have increased at a much higher rate over the last fifteen years, and those rates are very high compared to the rest of the country.<sup>40</sup> The theory of price elasticity tells us that this will have a dampening effect on

<sup>40</sup> California's average rates are approximately double Kentucky's average rates.

demand.<sup>41</sup> Second, state government has been strongly supportive of energy efficiency, and state efficiency standards and building codes will contribute to energy efficiency. Building codes can be very effective in a state with rapid growth, as new homes are required to be more efficient than old. Third, the public has been concerned with smog and other environmental issues, which should mean customer awareness of and support of the role that energy efficiency can play in mitigating environmental problems. Fourth, California utilities have supported energy efficiency programs for many years. This support may have been enhanced by decoupling, but we do not know by how much or what impact that support has had on energy efficiency.

### ***Impacts of Decoupling Mechanism***

The impact of decoupling on utilities is generally positive. Decoupling mechanisms reduce the variability of utilities' earnings. If the mechanism does not adjust for weather, but raises rates because of sales deviations caused by weather, this reduction in variability of earnings could be quite large. If the mechanism adjusts for any changes to weather normalized usage per customers, the utility will only get an increase in rates if sales actually decrease. If the mechanism adjusts for any change from projected weather normalized load, the utility would get an increase in rates when sales growth was less than projected. These various forms of reduction in revenue variability should result in some reduction of risk, which may be translated into lower required return on equity.

The impact on ratepayers is problematic. Decoupling shifts risks of sales reductions due not only to energy efficiency but to economic downturns from utilities to customers. This reduction in utility risk could be reflected in allowing a lower return on equity, but utilities have resisted this approach. Decoupling mechanisms will cause an increase in rates if sales decrease. Whether the increase is significant or not will depend on the magnitude of the change in sales. While these increases may be small, they may still create some confusion and disappointment in customers who adopted energy efficiency measures, as their reduction in usage will be partially offset by an increase in rates. There will also be some redistribution of revenue responsibility among customers within each rate class if all customers do not reduce usage equally. Since the mechanism provides the utility with the same fixed revenues as sales decrease, those customers who have not engaged in any energy efficiency will pay more as rates increase to maintain the level of revenues.

The impact of decoupling on regulatory agencies may also be a negative one. The initial establishment of a decoupling mechanism in itself requires additional regulatory oversight; for instance, if the mechanism is based on changes to forecast sales volumes, the sales forecast takes on considerable importance. The continuing utility requests for rate changes will require additional regulatory effort as well. The California ERAM adjustor requires very complex filings and oversight.

The impact of decoupling on utility support for energy efficiency appears to be positive. However, it is difficult to actually measure how important utility support is, and how important

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<sup>41</sup> The change in average use per customer may reflect the reduction in industrial customers (who tend to be the largest customers) in California.

decoupling is to utility support for DSM. Utility DSM programs that promote cost effective energy efficiency may result from the utilities' response to positive incentives or to the utilities' support of the concept of installing least cost resources. The American Council for Energy Efficient Economy, which ranks states energy efficiency efforts, ranked four states which do not have decoupling ahead of California.

***TASK 2D: How DSM Programs can be Designed, Implemented, and Costs Recovered***

This task examines potential means of implementing programs and recovering the cost of DSM programs and enhancing energy efficiency that are being utilized in Kentucky and elsewhere.

***The Regulatory Underpinnings of an Energy Efficiency Strategy***

Currently, utility filings regarding their Integrated Resource Planning (“IRP”) efforts, requests for approval of new generating facilities through a Certificate of Public Convenience and Necessity (“CPCN”), and their DSM Programs appear to be separate efforts. The IRP review evidently does not at present entail a full case, investigation, and enforceable findings.

The Integrated Resource Plan should be central to resource planning, and should provide the basis for both DSM programs and requests to construct new generation. At the present time in Kentucky, the IRP process is an informal process. Although Staff issues a report on the utilities’ filings, such a report does not carry the weight of a Commission order. Staff report findings are not directly enforceable as a result of the IRP process, but are rather recommendations on how to improve the next IRP. Although the IRP plans are “referenced” when utilities file CPCNs and DSM programs, the lack of direct connection and the lack of enforceability create the potential for significant gaps in effective planning. Environmental compliance plans must also be addressed at the same time, so that the cost of environmental compliance is taken into consideration in planning.

Without a consistent approach and strong regulatory oversight, a number of problems are possible. For instance, a CPCN filing may be based on different cost and load assumptions than had been used in the most recent prior IRP report. Without enforceability of the IRP plan, subsequent DSM programs may not achieve the cost effective level of energy efficiency, and generation additions may have to be larger in order than they would have been if the IRP plan had been enforceable. This could occur even if the utility’s actions appeared to have been “consistent” with its IRP plan.

If the IRP, DSM, and Environmental Compliance plans, and any subsequent CPCNs were required to be consistent, all resources, both supply and demand-side, would be compared on a level playing field, with the same assumptions about resource costs, program savings and costs, and future loads. The approach would also be more comprehensive since resources would be considered on a portfolio basis.

***Kentucky Utilities’ DSM Programs***

The Kentucky IOUs have developed DSM programs to offer to their customers, based on programs that pass certain tests as approved by the Public Service Commission. The utilities

administer these programs directly. The Cooperatives appear to offer much less in substantive programs.

In July of 2007, KU and LG&E jointly filed their DSM application for expanding existing programs and adding more programs, mostly targeting residential and commercial customers. More DSM programs were found cost effective using cost/benefit tests this year, likely due to increased rates. Overall, all the proposed programs are expected to have cumulative reductions in load of 142 MW by 2010 and 303 MW by 2014.<sup>42</sup>

As noted in Section 1A, the Kentucky IOUs' Demand-Side Management Cost Recovery Mechanisms consists of a formula that allows the utilities to recover costs associated with demand-side management programs through formula based Demand-Side Management Cost Recovery Mechanisms which should track actual costs, an incentive, and also lost revenue. As noted earlier in this report, this will provide no recovery for revenue reductions which may result from other sources, including customer-initiated energy efficiency improvements.

One important issue to note is that under KRS 278.285, industrial (energy-intensive) customers who implement cost-effective energy efficiency measures themselves can opt out of being assigned a DSM cost. Because of this provision, there is a lack of utility DSM programs targeted at large industrial customers in Kentucky. Since industrial customers may not choose to implement all measures that could be cost-effective, this provision may reduce DSM potential in the state.

### ***Non-Utility Administration of Energy Efficiency***

One way of addressing potential utility disincentives to fostering energy efficiency, is to remove this responsibility from utilities. Several states have chosen to create energy efficiency programs delivered through non-utility administrators, instead of requiring utilities to administer energy efficiency programs. Sometimes the states have taken on the work for providing energy efficiency services and in other cases the state has contracted a consultant or group of consultants to implement the programs.

To fund non-utility programs, states charge all customers who are eligible for energy efficiency services a public or system benefits charge ("SBC")<sup>43</sup>.

#### ***Pros***

- State can offer programs that are consistent throughout the state with the potential for consolidated administration and marketing costs and initiatives.
- The consumer can better distinguish between the entity who is selling electricity to them and the entity promoting conservation.

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<sup>42</sup> Case No. 2007-00319, filed July 19, 2007.

<sup>43</sup> In Vermont, the funding is collected by the utilities and provided to an agency that is independent of the state.

- Allows the state to refine or tailor the program without having to negotiate with the utilities.
- Administrators carrying out the work have a single focus on the program goals and are not distracted by other corporate goals of the utility.
- Performance incentives, shared savings and penalties can be built into the contract.
- Utility no longer needs to calculate or be compensated for its energy efficiency program costs and lost revenues.

### *Cons*

- There is the risk that public benefits funds may be raided by the legislature for uses other than energy efficiency.<sup>44</sup>
- Some entity must be responsible for setting program targets and cost recovery.
- The utility but not the efficiency agency has the customers' usage history and an existing relationship.
- Utilities might still promote load-building efforts which can send consumers a mixed signal.
- A distinct funding stream can lead to a disconnect in resource planning between energy efficiency and other resources.
- Utility earnings may be negatively impacted by energy efficiency programs implemented by the agency, unless there is some recognition of revenue impact.

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<sup>44</sup> This has happened in Wisconsin, Illinois, Ohio, Connecticut and Delaware.

## RECOMMENDATIONS

Kentucky's history of very low electric costs has been changing - and it will change further as load growth necessitates building new capacity. It could change rather dramatically because of new environmental regulations. Kentucky's electric rate history explains why Kentucky electric customers use more electricity than in the U.S. as a whole, and why until recent there has not been a strong interest in improving energy efficiency. The changing cost situation and broader environmental concerns call for a number of responses. It will take time for all of the suggested response to have an impact on load. To avoid enough load five years in the future in order to delay building a power plant requires action soon.

### ***Building codes and efficiency standards***

We recommend that Kentucky should effectively utilize building codes and efficiency standards for new electric equipment, when cost justified, which may require enforcement of such codes and standards. Customers usually do not understand the long run results of the electric usage, and tend to make decisions on the basis of a short time horizon. Building codes and efficiency standards are means of increasing the efficiency of electric use that may not result from purely voluntary decisions.

### ***Rate Design***

We recommend that Kentucky consider various rate design changes that can contribute to energy efficiency. These include seasonal rates, possibly increasing block rates, and time-of-use rates that better communicate marginal costs. While this may not require large changes, this approach will introduce changes that may become even more important in the future.

### ***Approach to DSM***

At the present time, utility DSM programs may be missing a potential for a large amount of energy efficiency that could result from industrial programs. Programs appear not to have been developed for this class. The ability of industrial customers to avoid paying for any DSM by stating that they have instituted energy efficiency seems to be the reason that programs have not been developed for this class. Industrial customers generally will not have the knowledge, and may not have the inclination, to implement all cost effective DSM. Their decisions regarding energy efficiency will have been informed by their current electric rates and not by knowledge of marginal costs. Such decisions are unlikely to yield the same result that an analysis of the long-run impact of DSM will have on energy costs. Given the legislative provision regarding industrial customers' ability to opt out, we recommend that the Commission adopt a procedure to review whether the alternative measures are "cost-effective" on the same basis that is used to judge utility programs.

***Decoupling***

We recommend that decoupling should be adopted only after full consideration of all of the impacts of decoupling and if it is determined that the benefits outweigh the costs. This should include an investigation of how much incremental impact it will have on utilities' DSM programs, and in particular whether existing ratemaking methodology, including a lost revenues component to DSM and possibly a modified incentive to utilities, can achieve the same result. It should also include consideration of how it will impact utilities, ratepayers, and regulators.

***Incentives for Efficiency programs***

We recommend that Kentucky investigate what level of incentives and possibly penalties will be effective in encouraging implementation of cost effective DSM. Incentives for efficiency programs may be necessary, but they should be related to utility performance rather than simply the amount spent. Incentives that reward utilities for spending more encourage utilities to spend more, but unless there is very thorough oversight, the larger spending may not achieve the energy efficiency potential of the state.

***Integrating Demand and Supply Planning***

The Commission should provide firm direction to the utilities in IRP, DSM and Environmental Compliance proceedings, utilizing the same information that is or will be used in CPCNs. The Commission should review and make enforceable findings regarding the IRPs and DSM programs. Without this oversight and direction, supply planning and energy efficiency programs are less likely to achieve the Commission's major overriding goals. For instance, the PSC staff has recommended changes in screening of DSM which have and which will result in additional programs being included. The impact of such enhanced programs should be integrated into resource planning, as noted earlier. The IRP process can and should ensure that before plans to build expensive new generating facilities are approved, the utility has reflected the potential reductions in demand that will result from building codes, customer initiated energy efficiency, and DSM programs. This approach is being taken by many states where utilities are vertically integrated.